Chapter 1

Introduction and Survey

Power system synchronous or angle instability phenomenon limits power transfer, especially where transmission distances are long. This is well recognized and many methods have been developed to improve stability and increase allowable power transfers [1-1,1-2,1-3]. Section 1.1 reviews the basics of power system stability.

The synchronous stability problem has been fairly well solved by fast fault clearing, thyristor exciters, power system stabilizers, and a variety of other stability controls such as generator tripping. Fault clearing of severe short circuits can be less than three cycles (50 ms for 60 Hz frequency). The effect of the faulted line outage on generator acceleration and stability may be greater than that of the short circuit itself.

Nevertheless, requirements for more intensive use of available generation and transmission, more onerous load characteristics, greater variation in power schedules, and industry restructuring pose new challenges. Recent large-scale power failures in North and South America and in other parts of the world have heightened the concerns.

This report on advanced angle stability controls provides industry guidance in solving stability problems with new or relatively new technologies. The technologies include control theory and applications, power electronics, microprocessor controllers, signal processing, digital and optical transducers, and telecommunications. There is great opportunity for synergism in these areas. The goals are new control strategies that are effective and robust. Effective in an engineering sense means "cost-effective." Control robustness is the capability to function appropriately for a wide range of power system operating and disturbance conditions.

Much can be gained by technology transfer to the electric power industry from disciplines such as automatic control, artificial intelligence, and signal processing.

Power system engineers responsible for determining stability-related transfer limits and for developing means for extending transfer limits are always acquainted with state-of-the-art control technology. Protection or other engineers responsible for implementation of stability controls may not be entirely familiar with control technology or power system stability phenomena. This report provides guidance on advanced methods to improve stability.

The initial incentives for this report were advances in synchronized voltage phase angle measurements and in high voltage power electronic equipment to directly or indirectly control transmission voltage and generator rotor angles. These concepts were discussed at a panel session on "More Effective Networks" at the 1996 general meeting in Paris; the panel session involved eight study committees. Christensen further described such concepts in [1-4]. An interesting question arose:

- What is the value of *direct* control of voltage phase angle? Equipment such as power-electronic controlled series compensation and phase-shifting transformers may directly control the phase angle (and indirectly control generator rotor angles).

A more comprehensive review of advanced technology for stability control is, however, desirable. Our emphasis in this report is on angle stability, but there is a close relation between voltage magnitude control and angle stability. Our emphasis is also on large disturbances and nonlinear aspects of stability control. The techniques described are applicable to practical large-scale power systems.

This introductory chapter surveys the field of power system stability controls, and the possibilities for advanced angle stability controls that are described in the following chapters.

1.1 Review of Power System Synchronous Stability Basics

Many publications, for example references 1-1, 1-2, and 1-5, describe the basics—which we briefly review here. Power generation is largely obtained by synchronous generators, which may be interconnected over thousands of kilometers in very large power systems. All generators must operate in synchronism during normal and disturbance conditions. Loss of synchronism of a generator or a group of generators with respect to another group of generators is *instability* that could result in expensive widespread power blackouts.

The essence of synchronous stability is balance of individual generator electrical and mechanical torques as described by Newton's second law applied to rotation:

$$J\frac{d\omega}{dt} = T_{\mathrm{m}} - T_{\mathrm{e}}\,,$$

where J is moment of inertia of the generator and prime mover, ω is speed, T_{m} is mechanical prime mover torque, and T_{e} is electrical torque related to generator electric power output. The generator speed determines the generator rotor angle changes relative to other generators. Figure 1-1 shows the basic "swing equation" block diagram relationship for a generator connected to a power system.

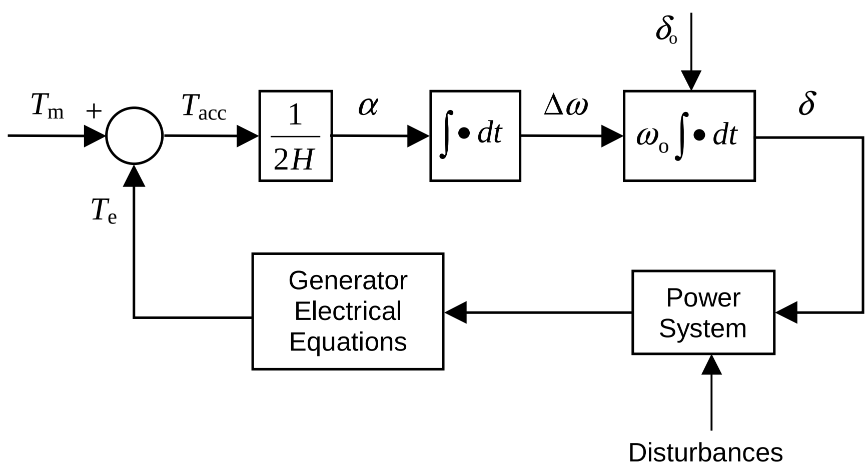

Fig. 1-1. Block diagram of generator electromechanical dynamics.

The block diagram representing the internal generator dynamics is explained as follows:

- The inertia constant, H, is proportional to the moment of inertia and is the kinetic energy at rated speed divided by the generator MVA rating. Units are MW-seconds/MVA (or seconds).
- T_{m} is mechanical torque in per unit. As a first approximation it's assumed to be constant. It is, however, influenced by speed controls (governors) and prime mover and energy supply system dynamics.
- ω_{o} is rated frequency in radians/second ($2\pi f_{\mathrm{o}}$, where f_{o} is rated frequency in Hz).
- δ_{o} is pre-disturbance rotor angle in radians relative to a reference generator.
- The power system block comprises the transmission network, loads, power electronic devices, and other generators/prime movers/energy supply systems with their controls. The transmission network is generally represented by algebraic equations. Loads and generators are represented by algebraic and differential equations.
- Disturbances include short circuits, and line and generator outages. A severe disturbance is a three-phase short circuit near the generator. This causes electric power and torque to be zero, with accelerating torque T_{acc} equal to T_{m}. (Although generator current is very high during the short circuit, its power factor, and active current and active power are close to zero.)

For illustration, a simple conceptual transmission model as shown in Fig. 1-2 is used. It comprises a remote generator connected to a large power system by two parallel transmission lines with an intermediate switching station. With some approximations adequate for a time of one second or more following a disturbance, the Figure 1-3 block diagram is realized. The basic relationship between power and torque is $P = T\omega$. Since speed changes are quite small, power is considered equal to torque in per unit. The generator representation is a constant voltage, E', behind a reactance. The transformer and transmission lines are represented by inductive reactances. Using the relation $S = E'I^*$, the generator electrical power has the well-known relation:

$$P_{\mathrm{e}} = \frac{E'V}{X}\sin\delta,$$

where V is the large system (infinite bus) voltage and X is the total reactance from the generator internal voltage to the infinite bus. The above equation approximates characteristics of a detailed, large-scale model, and illustrates that the power system is fundamentally a highly nonlinear system for large disturbances.

Figure 1-4 shows the relation between P_{e} and δ graphically. The pre-disturbance operating point is at the intersection of the load or mechanical power characteristic and the electrical power characteristic. Normal stable operation is at δ_{o}. For example, a small increase in mechanical power input causes an accelerating power ($P_{\mathrm{m}} - P_{\mathrm{e}}$) that increases δ to increase P_{e} until accelerating power returns to zero at a slightly different equilibrium point. The opposite is true for the unstable operating point at $\pi - \delta_o$: a small increase in mechanical power will cause a runaway increase in angle.

The angle δ_o is generally less than 45°. For small disturbances, the above power-angle equation can be linearized ($\sin\delta \cong \delta$ in radians for angles under 30°). The block diagram (Figure 1-3) would then represent a second order differential equation oscillator. For a remote generator connected to a large system the oscillation frequency is 0.8–1.1 Hz.

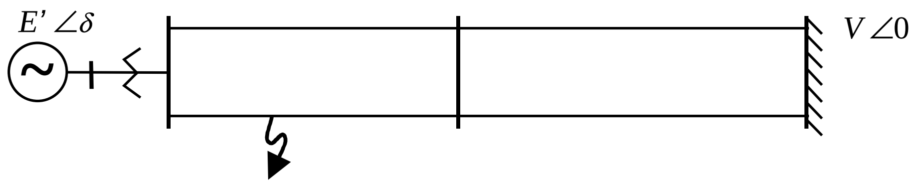

Fig. 1-2. Remote power plant to large system. Short circuit location is shown.

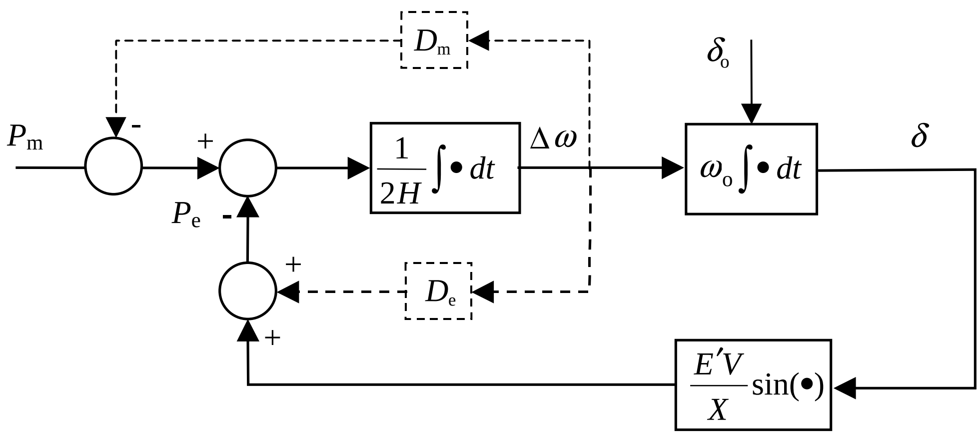

Fig. 1-3. Simplified block diagram of generator electromechanical dynamics.

During normal operation, mechanical and electrical torques are equal and the generator runs at a constant frequency close to 50 or 60 Hz rated frequency. If, however, a short circuit occurs on a transmission line the electric power output will be momentarily partially blocked from reaching loads and the generator (or group of generators) will accelerate, with increase in generator speed and angle. If the acceleration relative to other generators is too large, synchronism will be lost. Loss of synchronism is an unstable, runaway situation with large variations of voltages and currents that will normally cause protective separation of a generator or a group of generators. Following clearing of the short circuit by line removal, the increase in the electrical torque (and power) developed as the angle increases will decelerate the generator. If deceleration reverses the angle swing prior to $\pi - \delta_o'$, stability can be maintained at a new operating point δ_o' (Figure 1-4). If the angle swing is beyond $\pi - \delta_o'$, accelerating power/torque again becomes positive resulting in a runaway increase of angle and speed, and thus instability.

Figure 1-4 illustrates the equal area stability criterion for "first swing" stability. If the decelerating area (energy) above the mechanical power load line is greater the accelerating area below the load line, stability can be maintained.

Stability controls help maintain stability by decreasing the accelerating area or increasing the decelerating area. This may be achieved during the forward angle swing by increasing the electrical power output, or by decreasing the mechanical power input, or by both.

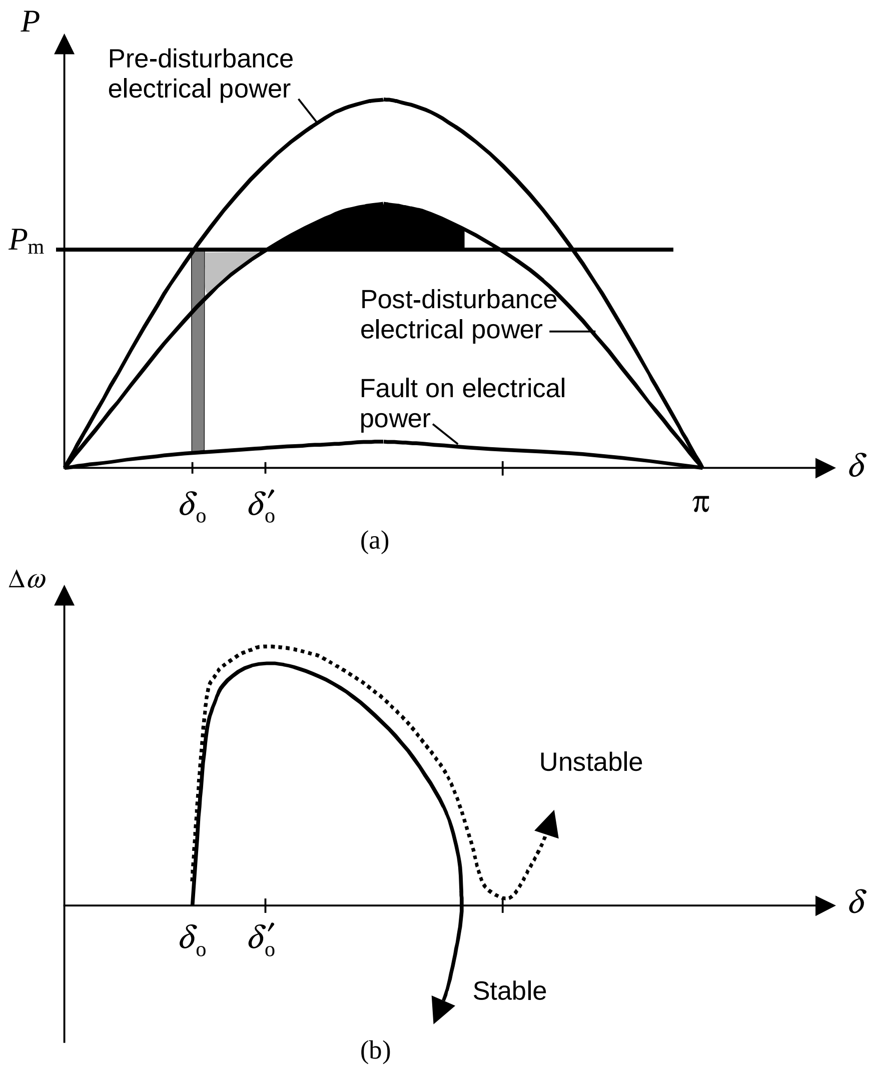

Fig. 1-4. (a) Power angle curve and equal area criterion. Dark shading for acceleration energy during fault. Light shading for additional acceleration energy because of line outage. Black shading for deceleration energy. (b) Angle–speed phase plane. Dotted trajectory is for unstable case.

Figure 1-3 also shows mechanical and electrical damping paths (dashed, damping power in phase with speed) that represent oscillation damping mechanisms respectively in the prime-mover and generator, loads, and other devices. For positive $\Delta\omega$ the mechanical damping, including friction and windage losses, reduces the mechanical input torque whereas the electrical damping enhances the electrical output torque. Controls, notably generator automatic voltage regulators with high gains, can introduce negative electrical damping at some oscillation frequencies. (In any feedback control system, high gain combined with time delays can cause positive feedback and instability.) For stability, the net damping must be positive for both normal conditions and for large disturbances with outages.

External stability controls may also be added to improve damping.

The above analysis can be generalized to large interconnected systems. For first swing stability, synchronous stability between two critical groups of generators is usually of concern. For damping, many oscillation modes are present, all of which require positive damping. The low frequency modes (0.1–0.8 Hz) associated with interarea oscillations between large portions of a power system are the most difficult to damp.

1.2 Concepts of Power System Stability Controls

Figure 1-5 shows a general structure for analysis of power system stability, and for development of power system stability controls.

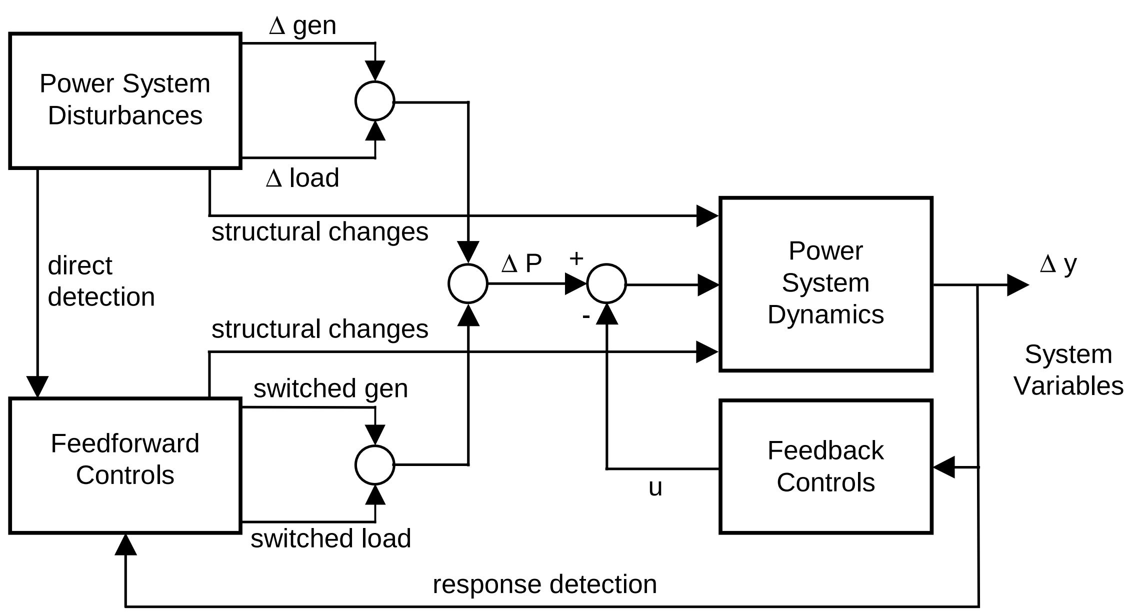

Fig. 1-5. General power system structure showing stability controls [1-8].

Stability problems typically involve disturbances such as short circuits, with subsequent removal of faulted elements. Generation or load may be lost, resulting in generation–load imbalance and frequency excursions. These disturbances stimulate power system electromechanical dynamics. Improperly designed or tuned controls may contribute to stability problems; as mentioned, one example is negative damping torques caused by generator automatic voltage regulators.

Because of power system synchronizing and damping forces (including the feedback controls shown on Figure 1-5), stability is maintained for most disturbances and operating conditions.

Feedback controls. The most important feedback (closed-loop) controls are the generator excitation controls (automatic voltage regulator often including power system stabilizer). Other feedback controls include prime mover controls, controls for reactive power compensation such as static var systems, and special controls for HVDC links. These controls are usually linear, continuously active, and based on local measurements.

There are, however, interesting possibilities for very effective discontinuous feedback controls, with microprocessors facilitating implementation. Discontinuous controls have certain advantages over continuous controls. Continuous feedback controls are potentially unstable. In complex power systems, continuously-controlled equipment may cause adverse modal interactions [1-7,8]. Modern digital controls, however, can be discontinuous, and take no action until certain monitored variables are out-of-range. This is analogous to the very effective biological systems that operate on the basis of excitatory stimuli [1-9].

Bang-bang discontinuous control can operate several times to control large amplitude oscillations, providing time for linear continuous controls to become effective.

Feedforward controls. Also shown on Figure 1-5 are specialized feedforward (open-loop) controls that are a powerful stabilizing force for severe disturbances and for highly stressed operating conditions. Short circuit or outage events can be directly detected to initiate pre-planned actions such as generator or load tripping, or reactive power compensation switching. These controls are rule-based, with rules developed from simulations (i.e., pattern recognition). These "event-based" controls are very effective since rapid control action prevents electromechanical dynamics from becoming stability threatening.

"Response-based" feedforward controls are also possible. These controls initiate stabilizing actions for arbitrary disturbances that cause significant "swing" of measured variables.

Feedforward controls such as generator or load tripping can ensure a post-disturbance equilibrium with sufficient region of attraction. With fast control action the region of attraction can be small compared to requirements with only feedback controls.

Feedforward controls have been termed discrete supplementary controls [1-5], special stability controls [1-3], special protection systems [1-10], remedial action schemes, and emergency control systems [1-11].

Generally speaking, feedforward controls can be very powerful. Although the reliability of special stability controls is often an issue [1-12], adequate reliability can be obtained by careful design. Controls are typically required to be as reliable as primary protective relaying. Duplicated or multiple sensors, redundant communications, and duplicated or voting logic are common [1-13]. Response-based controls are often less expensive than event-based controls because fewer sensors and communication paths are needed.

Undesired operation by some feedforward controls are relatively benign, and controls can be “trigger happy.” For example, infrequent misoperation or unnecessary operation of HVDC fast power change, reactive power compensation switching, temporary fast valving of fossil units, and transient excitation boosting may not be very disruptive. Misoperation of generator tripping (especially of steam-turbine generators), fast valving, load tripping, or controlled separation, however, are disruptive and costly.

Synchronizing and damping torques. Power system electromechanical stability means that synchronous generators and motors must remain in synchronism following disturbances — with positive damping of rotor angle oscillations (“swings”). For very severe disturbances and operating conditions, loss of synchronism (instability) occurs on the first swing within about one second. For less severe disturbances and operating conditions, instability may occur on the second or subsequent swings because of a combination of insufficient synchronizing and damping torques at synchronous machines.

Effectiveness and robustness. Power systems have many electromechanical oscillation modes, and each mode can potentially become unstable. Lower frequency interarea modes are the most difficult to stabilize. Controls must be designed to be effective for one or more modes and must not cause adverse interaction for other modes.

There are recent advances in robust control theory, especially for linear systems. For real nonlinear systems, emphasis should be on knowing uncertainty bounds and on sensitivity analysis using detailed nonlinear, large-scale simulation. For example, the sensitivity of controls to different operating conditions and load characteristics should be studied. On-line simulation using actual operating conditions reduces uncertainty, and can be used for control adaptation.

Actuators. Actuators may be mechanical or power electronic. There are tradeoffs between cost and performance. Mechanical actuators (circuit breakers) are lower cost, and are usually sufficiently fast for electromechanical stability (e.g., two-cycle opening time, five-cycle closing time). They have restricted operating frequency and are generally used for feedforward controls.

Circuit breaker technology and reliability have improved in recent years [1-14,1-15]. Bang-bang control (up to perhaps five operations) for interarea oscillations with periods of two seconds or longer is feasible [1-16]. Mechanical switching has traditionally used simple relays, but with advanced technologies and intelligent controls [1-17], it can approach or even exceed the sophistication of controls of, for example, thyristor-switched capacitor banks.

Power electronic phase control or switching using thyristors has been widely used in generator exciters, HVDC links, and static var compensators. Newer devices, especially gate-turnoff thyristors, now have voltage and current ratings sufficient for high power transmission applications (other semiconductor devices with current turnoff capabilities are available at lower power ratings). Advantages of power electronic actuators are very fast control, unrestricted switching frequency, and minimal transients and maintenance.

For economy, existing actuators, perhaps supplemented with intelligent controls, should be used to the extent possible. These include generator excitation and prime mover equipment, HVDC transmission equipment, and circuit breakers. For example, infrequent generator tripping may be cost-effective compared to new power electronic actuated equipment.

Reliability criteria. Experience shows that instability incidents are usually not caused by three-phase faults near large generating plants that are typically specified in deterministic reliability criteria. Rather they are the result of a combination of unusual failures and unforeseen circumstances. The three-phase fault reliability criterion is often considered an *umbrella* criterion providing a sufficient stability margin for less predictable disturbances involving multiple failures such as single-phase short circuits with "sympathetic" tripping of unfaulted lines. Of main concern is multiple *related* (common-mode) failures involving lines on the same right-of-way or with common terminations.

Reliability criteria also provide a performance margin to account for the many uncertainties in simulation analysis. Uncertainties can include modeling and data errors, and differences between the simulated and the actual operating conditions. Simulations are usually off line, and are often performed several months before actual operation. On-line, near real-time simulations reduces operating condition uncertainty.

Reliability criteria margins can be, for example, a power margin on allowable transfer (typically 5%), or a voltage dip of no more than 20–30% during swings.

Purpose of stability controls. The purpose of stability controls is to remove stability as a limit on power transfers. Excessive investment to obtain high performance such as rapid damping of oscillations is not desirable.

1.3 Types of Power System Stability Controls and Possibilities for Advanced Controls

Stability controls are of many types including:

- Generator excitation controls
- Prime mover controls including fast valving
- Generator tripping
- Fast fault clearing
- High speed reclosing, and single-pole switching
- Dynamic braking
- Load tripping and modulation
- Reactive power compensation switching or modulation (series and shunt)
- Current and voltage injections by voltage source inverter devices (STATCOM, UPFC, SMES, battery storage)

- Fast voltage phase angle control
- HVDC link supplementary controls
- Adjustable-speed (doubly-fed) generation
- Controlled separation and underfrequency load shedding

We will summarize these controls. Chapter 17 of reference 1-2 provides considerable additional information. Reference 1-18 describes use of many of these controls in Japan.

Excitation control. Generator excitation controls are a basic stability control. Thyristor exciters with high ceiling voltage provide powerful and economical means to ensure stability for large disturbances. Modern automatic voltage regulators and power system stabilizers are digital, facilitating additional capabilities such as adaptive control and special logic [1-19–22].

Excitation control is usually based on local measurements. Therefore full effectiveness may not be obtained for interarea stability problems where local measurements are not sufficient. Line drop compensation [1-23–24] is one method to increase the effectiveness (sensitivity) of excitation control, and to improve coordination with static var compensators that normally control transmission voltage with small droops.

Several forms of discontinuous control have been applied to keep excitation field voltage near ceiling levels during the first forward interarea swing [1-2,1-25,1-26]. Recalling the proposed use of angle measurement for stability control, the control described in references 1-2 and 1-25 computes change in rotor angle locally from the power system stabilizer (PSS) speed change signal. The control described in reference 1-26 is a feedforward control that injects a decaying pulse into the voltage regulators at a large power plant following direct detection of a large disturbance. Figure 1-6 shows simulation results using this Transient Excitation Boosting TEB.

Prime mover control including fast valving. Fast mechanical power reduction (fast valving) at generators is an effective means of stability improvement. Use has been limited, however, because of the coordination required between characteristics of the electrical power system, the prime mover and prime mover controls, and the energy supply system (boiler).

Digital prime mover controls facilitate addition of special features for stability enhancement. Digital boiler controls, often retrofitted on existing equipment, may improve the feasibility of fast valving. Although not common, turbine power can be modulated by prime movers controls to improve damping of interarea oscillations.

Fast valving has been found to be lower cost than tripping of turbo-generators. References 1-2 and 1-27 describe investigations and recent implementations of fast valving. In the AEP application at Rockport [1-27], temporary fast valving has been found to be attractive, since both the first cost and operating costs of these fast valving schemes are less than the best alternative, which include additional transmission circuits. AEP and several other utilities make continual use of this means of improving rotor angle stability,

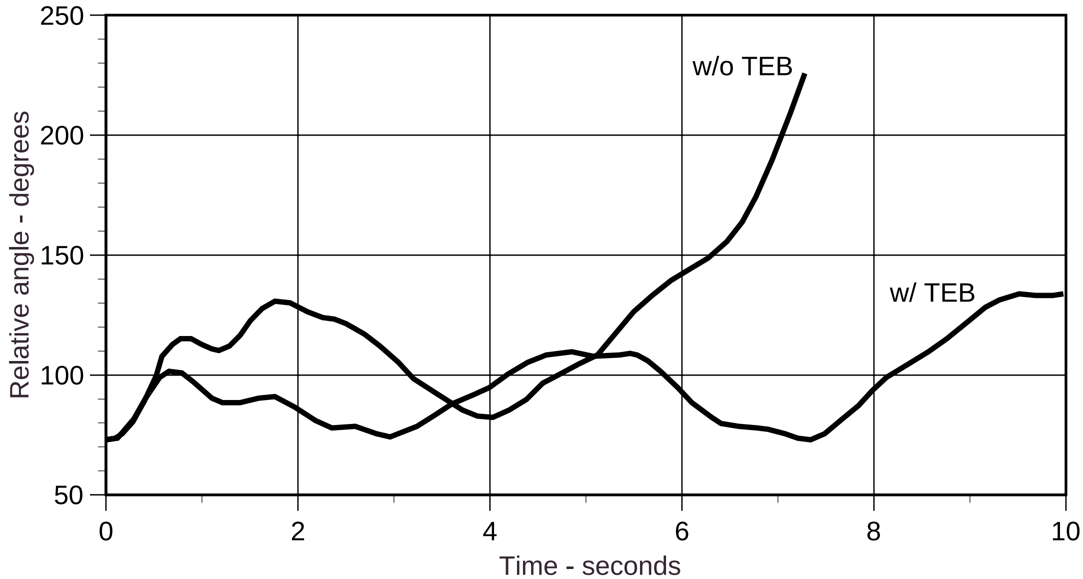

Fig. 1-6. Rotor angle swing of Grand Coulee Unit 19 in Pacific Northwest relative to the San Onofre nuclear plant in Southern California. The effect of transient excitation boosting (TEB) at the Grand Coulee Third Power Plant following bipolar outage of the Pacific HVDC Intertie (3100 MW) is shown [1-26].

although few of these applications are documented in the literature. Sustained fast valving (sustained power reduction) may be necessary for a stable post-disturbance equilibrium.

AEP routinely reexamines the stability of the Rockport generation–transmission complex and the effectiveness of temporary fast valving. The Rockport Operating Guide is updated to reflect changes in operating conditions, changes in controls or operating practices, and changes in the regional transmission network. Figure 1-7 illustrates the effectiveness of the fast valving. The simulated operating conditions and event include a single prior outage and a single phase fault, unsuccessfully cleared by single-phase switching at +50 milliseconds, with successful backup three phase clearing 0.55 seconds after the fault. The plots are of the consequent changes in speed and rotor angle position. The upper plots of Figure 1-7 are with temporary fast valving, and the lower plots are without fast valving.

Generator tripping. Generator tripping is an effective and economic control especially if hydro units are used. Tripping of fossil units, especially gas- or oil-fired units, may be attractive if tripping to house load is possible and reliable. Gas turbine and combined-cycle plants constitute a large percentage of new generation. Occasional tripping of these units is feasible and can become an attractive stability control in the future.

Most generator tripping controls are event-based (based on outage of generating plant out-going lines or outage of tie lines). Several advanced response-based generator tripping controls, however, have been implemented.

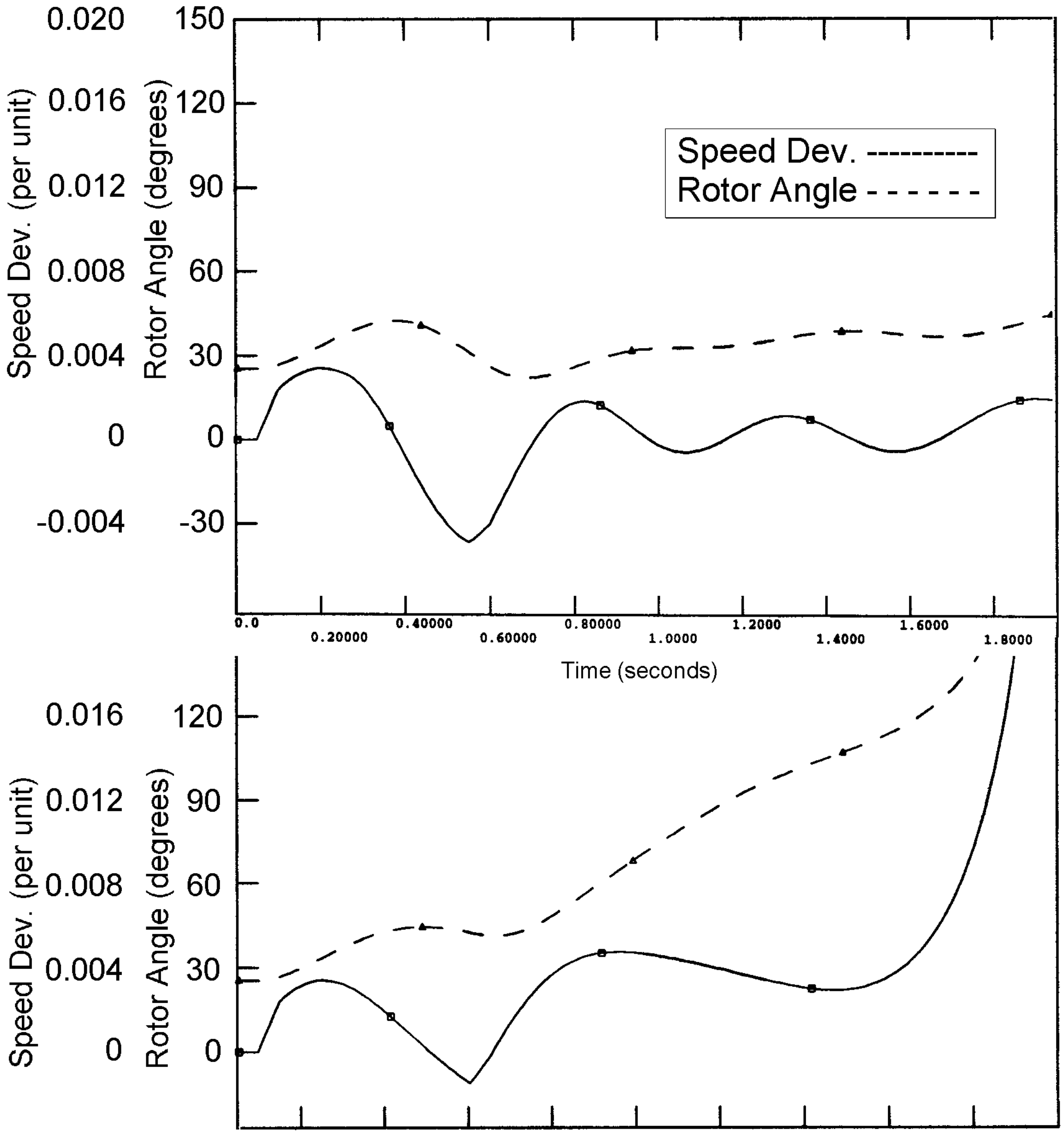

Fig. 1-7. Simulation of effect of temporary fast valving at Rockport for prior circuit outage and single-phase fault with unsuccessful single-pole switching. Top plots are with fast valving and bottom plots are without fast valving.

The Acceleration Trend Relay (ATR) is implemented at the Colstrip generating plant in eastern Montana [1-28]. The plant consists of two 330 MW units and two 700 MW units. The microprocessor-based controller measures rotor speed and generator power, and computes acceleration and angle. Tripping of 16–100% of plant generation is based on eleven trip algorithms involving acceleration, speed and angle changes. Because of the long distance to Pacific Northwest load centers, the ATR has operated many times, both desirably and undesirably. There are proposals to use voltage angle measurement information (Colstrip 500-kV voltage angle relative to Grand Coulee and other Northwest locations) to adaptively adjust ATR settings, or as additional information for trip algorithms. Another possibility is to provide speed or frequency measurements from Grand Coulee and other locations to base algorithms on speed difference rather than only the local Colstrip speed [1-29].

A Tokyo Electric Power Company stabilizing control predicts generator angle changes and decides the minimum number of generators to trip [1-30]. Local generator electric power, voltage and current measurements are used to estimate angles. The control has worked correctly for several actual disturbances.

The Tokyo Electric Power Company is also developing an emergency control system which uses a predictive prevention method for step-out of pumped storage generators [1-31,1-32]. In the new method, the generators in TEPCO's network which swing against their local pumped storage generators after serious fault are treated as an external power system. The parameters in the external system, such as angle and inertia, are estimated by using local on-line information. The behavior of a local pumped storage generator is predicted based on equations of motion. Control actions (the number of generators to be tripped) are determined based on the prediction.

Reference 1-33 describes response-based generator tripping using a phase-plane controller. The controller is based on the apparent resistance/rate of change of apparent resistance (*R*–*R*dot) phase plane, which is closely related to an angle difference/speed difference phase plane between two areas. The primary use of the controller is for controlled separation of the Pacific AC Intertie. Figure 1-8 shows simulation results where 600 MW of generator tripping reduces the likelihood of controlled separation.

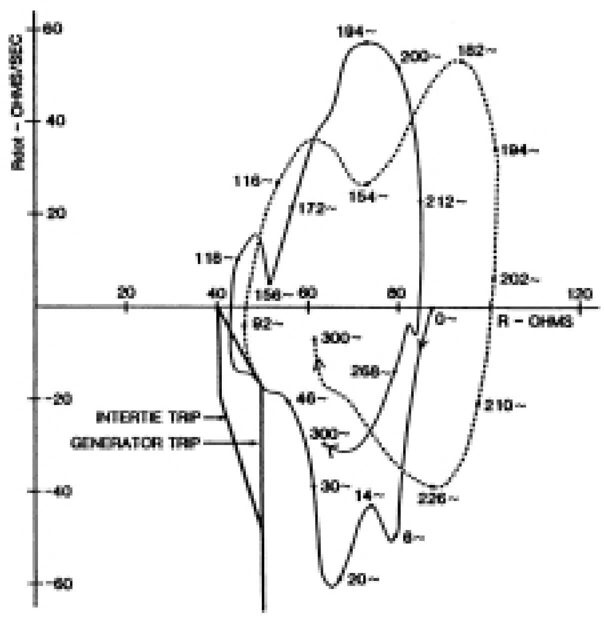

Fig. 1-8. *R*–*R*dot phase plane for loss of Pacific HVDC Intertie (2000 MW). Solid trajectory is without additional generator tripping. Dashed trajectory is with additional 600 MW of generator tripping initiated by the *R*–*R*dot controller generator trip switching line [1-33].

Fast fault clearing, high-speed reclosing, and single-pole switching. Clearing time of close-in faults can be less than three cycles using conventional protective relays and circuit breakers. Typical EHV circuit breakers have two-cycle opening time. One-cycle breakers have been developed [1-34], but special breakers are seldom justified. High magnitude short circuits may be detected as fast as one-fourth cycle by non-directional overcurrent relays. Ultra-high-speed traveling wave relays are also available [1-35]. With such short clearing times, and considering that most EHV faults are single-phase, the removed transmission lines or other elements may be the major contributor to generator acceleration. This is especially true if non-faulted equipment is removed by "sympathetic" relaying.

High-speed three-pole reclosing is an effective method of improving stability and reliability. Reclosing is before the maximum of the first forward angular swing, but after 30–40 cycle time for arc extinction. During a lightning storm, high speed reclosing keeps the maximum number of lines in service. High-speed reclosing is effective when unfaulted lines trip because of relay misoperations.

Unsuccessful high-speed reclosing into a permanent fault can cause instability, and can also compound the torsional duty imposed on turbine-generator shafts. Solutions include reclosing only for single-phase faults, and reclosing from the weak end with hot-line checking prior to reclosing at the generator end. Communication signals from the weak end indicating successful reclosing can also be used to enable reclosing at the generator end [1-38].

Single-pole switching is a practical means to improve stability and reliability in EHV networks where most circuit breakers have independent pole operation [1-36,1-37]. Several methods are used to ensure secondary arc extinction. For short lines, no special methods are needed. For long lines, the four-reactor scheme [1-39,1-40] is most commonly used. High-speed grounding switches may be used [1-41]. A hybrid reclosing method used by Bonneville Power Administration employs single-pole tripping, but with three-pole tripping on the backswing followed by rapid three-pole reclosure; the three-pole tripping ensures secondary arc extinction [1-36].

Single-pole switching may necessitate positive sequence filtering in stability control input signals.

For advanced stability control, signal processing and pattern recognition techniques may be developed to detect secondary arc extinction [1-42,1-43]. Reclosing into a fault is avoided and single-pole reclosing success is improved.

High-speed reclosing or single-pole switching may not allow increased power transfers because deterministic reliability criteria generally specifies permanent faults. Nevertheless, fast reclosing provides "defense-in-depth" for frequently occurring single-phase temporary faults and false operation of protective relays. The probability of power failures because of multiple line outages is greatly reduced.

Dynamic braking. Shunt dynamic brakes using mechanical switching have been used infrequently [1-2]. Normally the insertion time is fixed. One attractive method not requiring switching is neutral-to-ground resistors in generator step-up transformers. Braking automatically results for ground faults — which are most common.

Often generator tripping, which helps ensure a post-disturbance equilibrium, is a better solution.

Thyristor switching of dynamic brakes has been proposed. Thyristor switching or phase control minimizes generator torsional duty [1-44], and can be a subsynchronous resonance countermeasure [1-45].

Load tripping and modulation. Load tripping is similar in concept to generator tripping but is at the receiving end to reduce deceleration of receiving-end generation. Interruptible industrial load is commonly used. For example, reference 1-46 describes tripping of up to 3000 MW of industrial load following outages during power import conditions.

Rather than tripping large blocks of industrial load, it may be possible to trip low priority commercial and residential load such as space and water heaters, or air conditioners. This is less disruptive and the consumer may not even notice brief interruptions. The feasibility of this control depends on implementation of direct load control as part of demand side management, and on the installation of high-speed communication links to consumers with high-speed actuators at load devices. Although unlikely because of economics, appliances such as heaters could be designed to provide frequency sensitivity by local measurements.

Load tripping is also used for voltage stability. Here the communication and actuator speeds are generally not as critical.

It's also possible to modulate loads such as heaters to damp oscillations [1-47–50]. This is described in Chapter 7.

Clearly load tripping or modulation of small loads will depend on the economics, and the development of fast communications and actuators.

Reactive power compensation switching or modulation. Controlled series or shunt compensation improves stability, with series compensation generally being the most cost effective [1-86]. For switched compensation, either mechanical or power electronic switches may be used. For continuous modulation, thyristor phase control of a reactor (TCR) is used. Mechanical switching has the advantage of lower cost. The operating times of circuit breakers are usually adequate, especially for interarea oscillations. Mechanical switching is generally single insertion of compensation for synchronizing support. In addition to previously mentioned advantages, power electronic control has advantages in subsynchronous resonance performance [1-51].

For synchronizing support, high-speed series capacitor switching has been used effectively on the North American Pacific AC intertie for over 25 years [1-52]. The main application is for full or partial outages of the parallel Pacific HVDC intertie (event-driven control using transfer trip over microwave radio). Series capacitors are inserted by circuit breaker opening; operators bypass the series capacitors some minutes after the event. Response-based control using an impedance relay was also used for some years, and new response-based controls are being investigated.

Thyristor-based series compensation switching or modulation has been developed with several installations in service or planned [1-10,1-53,1-54]. Thyristor-controlled series compensation (TCSC) allows significant time-current dependent increase in series capacitive reactance over the nominal reactance. With appropriate controls, this increase in reactance can be a powerful stabilizing force [1-55,1-56].

As described in Chapter 7, thyristor-controlled series compensation was chosen for the 1020 km, 500-kV intertie between the Brazilian north/northeast networks and the south/southeast networks [1-57]. Also described in Chapter 7 is a TCSC application in China for integration of a remote power plant using two parallel 500-kV transmission lines (1300 km). Transient stability simulations indicate that 25% thyristor controlled compensation is more effective than 45% fixed compensation. Several advanced TCSC control techniques are promising [1-58].

For synchronizing support, high speed switching of shunt capacitor banks is also effective. Again on the Pacific AC intertie, four 200 MVAr shunt banks are switched for HVDC and 500-kV ac line outages [1-16]; response-based controls based on voltage are installed.

High speed mechanical switching of shunt banks as part of a static var *system* is common. For example, the Forbes static var system near Duluth, Minnesota USA includes two 300 MVAr 500-kV shunt capacitor banks [1-59]. Generally it's cost-effective to augment power electronic controlled compensation with fixed or mechanically-switched compensation.

Static var compensators are applied along interconnections to improve synchronizing and damping support. Voltage support at intermediate points allow operation at angles above 90°. Reference 1-60 provides an example using five SVCs with only voltage control to improve stability for a proposed interconnection of the Scandinavian (Nordel) and main European (UCPTE) power systems.

SVCs are modulated to improve oscillation damping. One study [1-1,1-61] showed line current magnitude to be the most effective input signal. Synchronous condensers can provide similar benefits, but nowadays are usually not competitive with power electronic equipment. Available SVCs in load areas may be used to indirectly modulate load to provide synchronizing or damping forces.

Digital controls allow many new control strategies. Gain supervision and optimization adaptive control is common. For series or shunt power electronic devices, control mode selection allows bang-bang control, synchronizing versus damping control, and other non-linear and adaptive strategies.

Current injection by voltage source converters. Advanced power electronic controlled equipment employ gate turn-off thyristors or other devices with current turnoff capability. Reactive power injection devices include static compensator (STATCOM), static synchronous series compensator (SSSC), and unified power flow controller (UPFC). Reference 1-1 describes use of these devices for oscillation damping.

As with conventional thyristor-based equipment, it's often effective for voltage source inverter control to also coordinate mechanical switching.

Voltage source inverters may also be used for real power series or shunt injection. Superconducting magnetic energy storage (SMES) or battery storage is the most common. For angle stability control, injection of real power is more effective than reactive power. SMES or battery storage provides both active and reactive power control.

For transient stability improvement, SMES can be of smaller MVA size and possibly lower cost than a STATCOM. SMES may be less location dependent than a STATCOM.

Fast voltage phase angle control. Voltage phase angles and thereby rotor angles can be rapidly controlled by power electronic controlled series compensation (discussed above) or phase shifting transformers. This provides powerful stability control. Although one type of thyristor-controlled phase shifting transformer was developed almost twenty years ago [1-62], high cost has presumably prevented installations. Reference 1-63 describes an application study.

The unified power flow controller incorporates GTO-thyristor phase shifting and series compensation control, and one installation (not a transient stability application) is in service [1-53].

One concept employs power electronic series or phase shifting equipment to directly control angles across an interconnection within a small range [1-64]. On a power–angle curve, this can be visualized as keeping high synchronizing coefficient (slope of power–angle curve) during disturbances.

Bonneville Power Administration developed a novel method for transient stability by high speed 120° phase rotation of transmission lines between networks losing synchronism [1-54]. This technique is very powerful (perhaps too powerful!) and raises reliability and robustness issues especially in the usual case where several lines form the interconnection. It has not been implemented.

HVDC link supplementary controls. HVDC dc links are installed for power transfer reasons. In contrast to the above power electronic devices, the available HVDC converters provide the actuators so that stability control is inexpensive. For long distance HVDC links within a synchronous network, HVDC modulation can provide powerful stabilization, with active and reactive power injections at each converter. Control robustness, however, is a concern [1-1,1-7].

References 1-1, 1-65–67 and 1-87 describe HVDC link stability controls. The Pacific HVDC Intertie modulation control, implemented in 1976, is unique in that a remote input signal from the parallel Pacific AC Intertie was used. Figure 1-9 shows commissioning test results.

Adjustable-speed (doubly-fed) generation. References 1-1, 1-68, 1-69, and Appendix A describe stability benefits of adjustable speed synchronous machines that have been

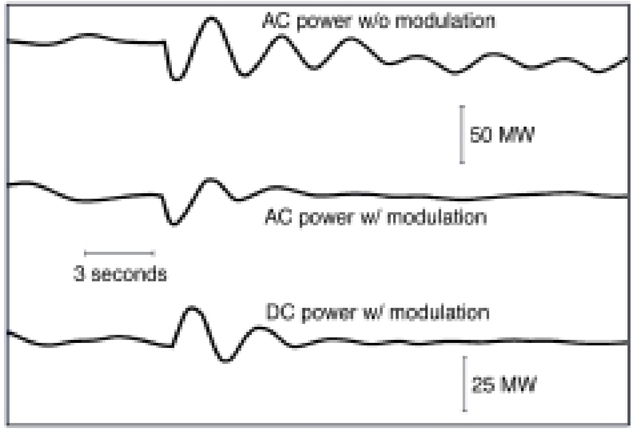

Fig. 1-9. System response to Pacific AC Intertie series capacitor bypass with and without dc modulation [1-66].

developed for pumped storage applications. Control of excitation frequency enables direct control of rotor angle. Since the frequency converter only supplies power to the rotor, the cost may be low enough to be competitive with alternatives. Reference 1-88 describes doubly-fed turbo-generators.

Controlled separation and underfrequency load shedding. For very severe disturbances and failures, maintaining synchronism may not be possible or cost-effective. Controlled separation (islanding) based on out-of-step detection or parallel path outages mitigates the effects of instability. The generation/load imbalances in the islands that are formed should be small enough that the islands stabilize. Undesirable generation tripping during voltage and frequency swings must be minimized through adequate control and protection design and settings. Underfrequency load shedding may be required in islands that were importing power.

References 1-33, 1-70, and 1-71 describe advanced controlled separation schemes. Recent proposals advocate use of voltage phase angle measurements for controlled separation.

1.4 Dynamic Security Assessment

Control design and settings, along with transfer limits, are usually based on off-line simulation (time and frequency domain), and on field tests. Controls must then operate appropriately for a variety of operating conditions and disturbances.

Recently, however, on-line dynamic (or transient) stability/security assessment software has been developed. State estimation and on-line power flow monitoring provide the base operating conditions. Simulation of potential disturbances is then based on actual operating conditions, reducing uncertainty of the control environment. Dynamic security assessment is presently used to determine arming levels for generator tripping controls [1-72,1-73].

With today's computer capabilities, hundreds or thousands of large-scale simulations may be run each day to provide an organized database of system stability properties. Security assessment is made efficient by techniques such as fast screening and contingency selection, and smart termination of strongly stable or unstable cases. Parallel computation is straightforward using multiple workstations for different simulation cases; common initiation may be used for the different contingencies

In the future, dynamic security assessment may be used for control adaptation to current operating conditions. Another possibility is stability control based on neural network or decision tree pattern recognition. Dynamic security assessment provides the database for pattern recognition techniques. Pattern recognition may be considered data compression of security assessment results.

Industry restructuring requiring near real-time power transfer capability determination may accelerate the implementation of dynamic security assessment, facilitating advanced stability controls.

We further describe on-line security assessment in Chapter 5.

1.5 Intelligent Controls

Mention has already been made of rule-based controls and pattern recognition based controls. Fuzzy logic may be used for rule-based control.

As a possibility, reference 1-74 describes a sophisticated self-organizing neural fuzzy controller (SONFC) based on the speed–acceleration phase plane. Compared to the angle–speed phase plane, control tends to be faster and both final states are zero (using angle, the post-disturbance equilibrium angle is not known in advance). The controllers are located at generator plants. Acceleration and speed can be easily measured/computed using, for example, the techniques developed for power system stabilizers.

The SONFC could be expanded to incorporate remote measurements. Dynamic security assessment simulations could be used for updating/retraining of the neural network fuzzy controller. The SONFC is suitable for generator tripping, series or shunt capacitor switching, HVDC control, etc.

We further describe intelligent controls in Chapter 4.

1.6 Effect of Industry Restructuring on Stability Controls

Industry restructuring will have many impacts on power system stability. New, frequently changing power transfer patterns cause new stability problems. Most stability and transfer capability problems must be solved by new controls and new substation equipment, rather than by new transmission lines [1-75].

Different ownership of generation, transmission and distribution makes necessary power *system* engineering more difficult. New power industry standards along with ancillary services mechanisms are being developed. Controls such as generator or load tripping, fast valving, higher than standard exciter ceilings, and power system stabilizers may be ancillary services. In large interconnections, independent grid operators or security coordination centers may facilitate dynamic security assessment and centralized stability controls.

We further describe the effect of industry restructuring on stability controls in Chapter 8.

1.7 Experience from Recent Power Failures

Recent cascading power outages demonstrated the impact of control and protection failures, the need for “defense-in-depth” or “multiple lines of defense,” and the need for advanced stability controls.

The July 2, 1996 and August 10, 1996 power failures [1-76–80] in western North America showed need for improvements and innovations in stability control areas such as:

- Fast insertion of reactive power compensation for voltage support, and fast generator tripping using response-based controls.
- HVDC, TCSC, and SVC control for stability.
- Power system stabilizer design and tuning.
- Controlled separation.
- Power system modeling and data validation for control design.
- Control adaptation to actual operating conditions.

Figure 1-10 shows the development of the August 10 breakup

Other blackouts have occurred recently in the North American Upper Midwest [1-80], and in Brazil. In Brazil, new emergency controls for generator/load tripping and controlled separation are being added.

Defense-in-depth/multiple line of defense for system reliability includes risk management in system operation (e.g., reduced power transfers during storm conditions), fast and reliable protective relaying, high-speed three or single pole reclosing, best practice local stability controls (e.g., thyristor exciters with PSS). The final lines of defense mitigate the effects of extreme disturbances, and may include generator/load tripping, controlled separation, and underfrequency or undervoltage load shedding.

1.8 Coordination with other CIGRÉ and Industry Work

References 1-1, 1-81, and 1-82 document recent CIGRÉ and IEEE work related to angle stability control. These works are valuable, providing comprehensive description of many aspects of stability. CIGRÉ TF 38.02.16, *Impact of Interactions among Power System Controls*, CIGRÉ TF 38.02.19, *System Protection in the Power System: modeling and analysis,* and CIGRÉ TF 38.02.20 *Advanced Power System Controls Using Intelligent Systems*, are currently underway.

Our intent is to complement rather than duplicate other industry work.

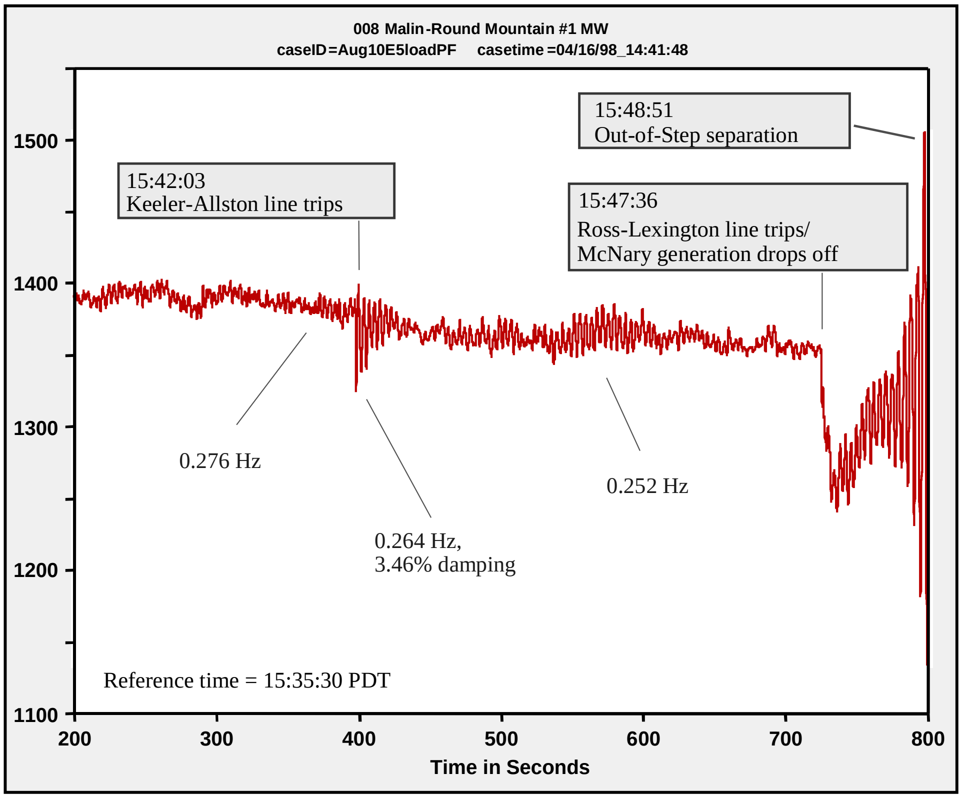

Fig. 1-10. Power flow on Oregon–California 500-kV line during initial portion of August 10, 1996 breakup. Following separation of the Pacific AC intertie, uncontrolled separations broke the system into four islands with loss of 30,489 MW of load.

1.9 Summary

Power system angle stability can be improved by a wide variety of controls. Some methods have been used effectively for many years, both at generating plants and in transmission networks. New control techniques and actuating equipment are promising.

This chapter provides a broad survey of available stability control techniques with emphasis on new and emerging technology. The following chapters provide in-depth evaluation of the many issues in the selection and design of stability controls.

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